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Development of Improved Blowout Prevention Procedures for Deep Water Drilling Operations

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DEVELOPMENT OF IMPROVED BLOWOUT PREVENTION PROCEDURES FOR DEEP WATER DRILLING OPERATIONS

Objective: To develop improved well control procedures for deep water floating drilling operations.

As the search for petroleum reserves has moved into the offshore environment, the blowout control problems associated with exploratory and development drilling has continued to increase in complexity. In addition, the difficulties in confining an offshore oil spill makes the environmental consequences of a blowout more important. Modern well control equipment was largely developed for land based drilling operations. This equipment can also be applied with minor modifications to bottom supported exploratory drilling vessels such as jackups and development rigs operating on an offshore platform. More significant modifications in blowout prevention equipment were required for exploratory drilling done from floating drilling vessels capable of drilling in water depths beyond the range of bottom supported vessels. One major modification was the location of the blowout preventer valves on the sea floor rather than at the surface. Subsea flowlines are used to connect the blowout preventer stack to the adjustable chokes at the surface.

A threatened blowout or "kick" in a well starts when the pressure exerted by the column of drilling fluid is less than the fluid pressure in a permeable formation which has been penetrated by the bit. Thereupon, formation fluid enters the well and displaces or "kicks" the drilling fluid from the wellbore annulus until the flow at the surface is stopped by closing the blowout preventers. Before normal drilling operations can be resumed, the formation fluids must be removed from the well and the density of the drilling fluid in the well increased sufficiently to prevent further influx of formation fluids. This is accomplished by circulating the well against a back-pressure provided by an emergency high-pressure flowline and an adjustable choke, using an appropriate well control procedure.

The special well control problems for floating drilling vessels stem primarily from the reduced fracture resistance of the marine sediments and the need for long vertical subsea choke lines between the subsea blowout preventer stack and the drilling vessel. The shallow marine sediments are often unconsolidated and undercompacted having a relatively low bulk density up to several thousand feet below the mudline. The fracture problem is made even more severe by the fact that the mud column extends far above the mudline to the flowline above sea level and mud density generally exceeds sea water density. Thus, when a kick occurs during deepwater drilling operations, formation fracture will usually occur at a lower equivalent mud density than for a similar situation on land. Shown in Figure 1 is a schematic diagram of the actual well geometry used on a well drilled in 4300 feet of water. The fracture gradient in this example was equivalent to the hydrostatic pressure created by only a 10.6 lb/gal drilling fluid.

The use of long vertical subsea choke lines in deep water between the subsea BOP stack and the drilling vessel has two detrimental aspects. The increased choke line length can result in unacceptably high circulating frictional pressure losses in the choke lines. This can be extremely important because present well control procedures are based on the assumption that frictional pressure losses held against the well annulus are small and can be applied as a convenient safety margin when circulation of the kick is initiated. In addition, since the subsea choke lines extend *vertically* over a considerable length, the density of the fluid in the choke lines contribute directly to the hydrostatic pressure in the well. When the top of a slug of low density kick fluid reaches the subsea BOP stack, the hydrostatic pressure of the drilling fluid in the choke line is quickly lost during the rapid elongation of the slug as it exits the large casing and proceeds upward through the small diameter choke line. This too is extremely important because present well control procedures are based on the assumption that significant well pressure changes will occur more slowly than the unsteady state readjustment time of the surface drill pipe pressure, upon which choke manipulation is based.

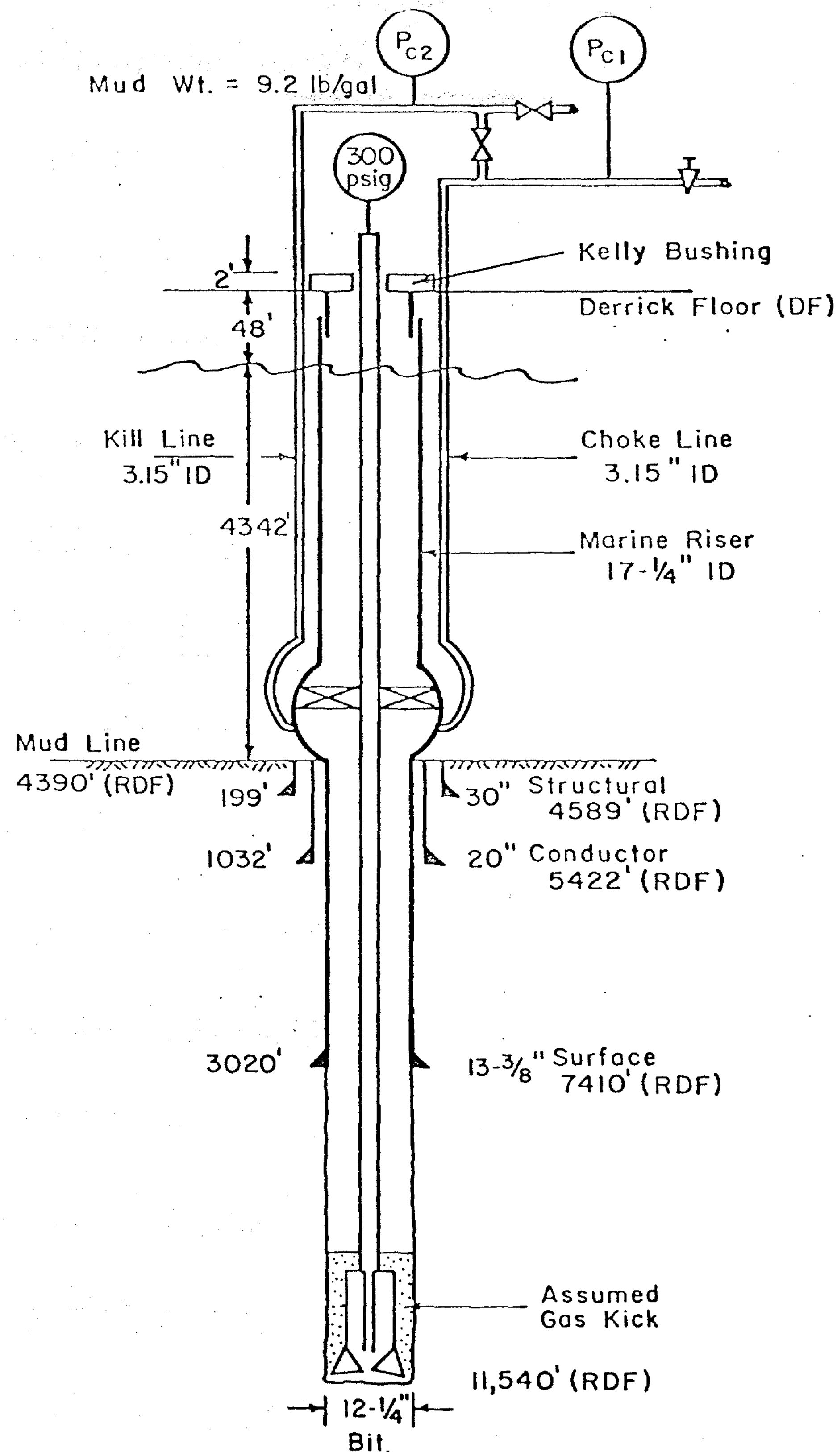


Figure 1: Schematic Diagram and Drilling Data for an Example Well Drilling in Deep Water

Figure 2 illustrates the importance of frictional pressure losses in the subsea choke line when circulation of a kick is initiated. Initially, the equivalent density at the casing seat for shut-in conditions is 10.0 ppge. Upon initiation of pumping at a kill rate of 5 bbl/min, using a 3 in. I.D. choke line, an additional 350 psi of pressure is added to the casing seat. This additional pressure increases the equivalent circulating density at the casing seat to 10.9 ppge, which is above the fracture gradient for the conditions given. Thus, fracturing of a formation exposed below the casing seat would occur, possibly resulting in an underground blowout.

The problem which occurs when low density kick fluid reaches the sea floor is illustrated in Figure 3. For a 30 bbl initial volume of gas influx, just prior to gas entering the choke line, the backpressure held using the surface choke must be maintained in this example at approximately 300 psia in order to keep the bottom hole pressure slightly above the formation pore pressure. However, after pumping the capacity of the choke line, which is a relatively small volume, the choke pressure required to keep the bottom hole pressure constant increases to approximately 1700 psia. It is very difficult for the choke operator to make such rapid changes in an accurate manner. Since no bottom hole pressure instrumentation is available, the choke operator can only ascertain bottom hole pressure changes by observing changes in the surface drill pipe pressure. The time required for pressure

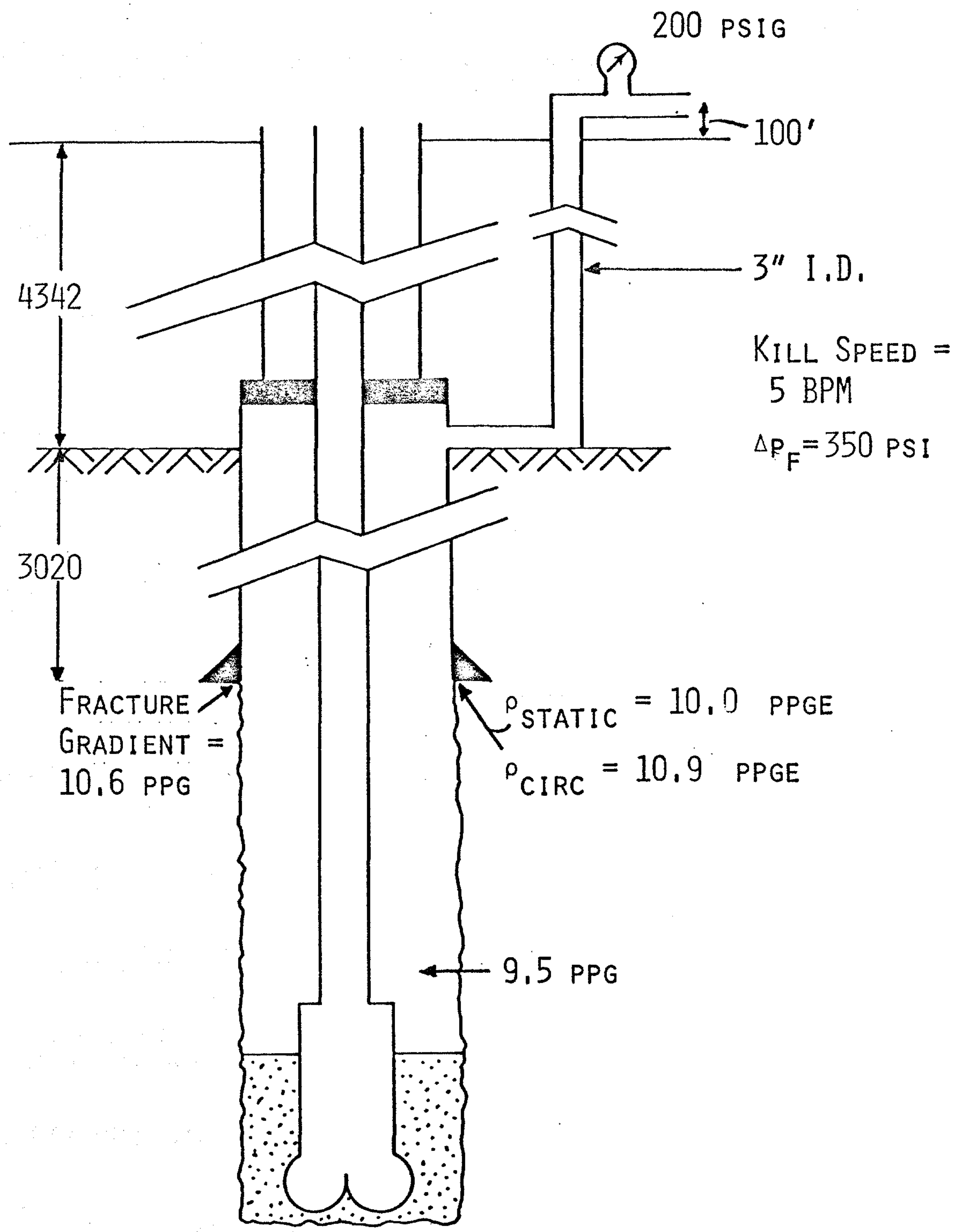


FIGURE 2 - EXAMPLE ILLUSTRATING EFFECT OF CHOKELINE FRICTIONAL PRESSURE LOSS ON EQUIVALENT MUD DENSITY AT CASING SEAT

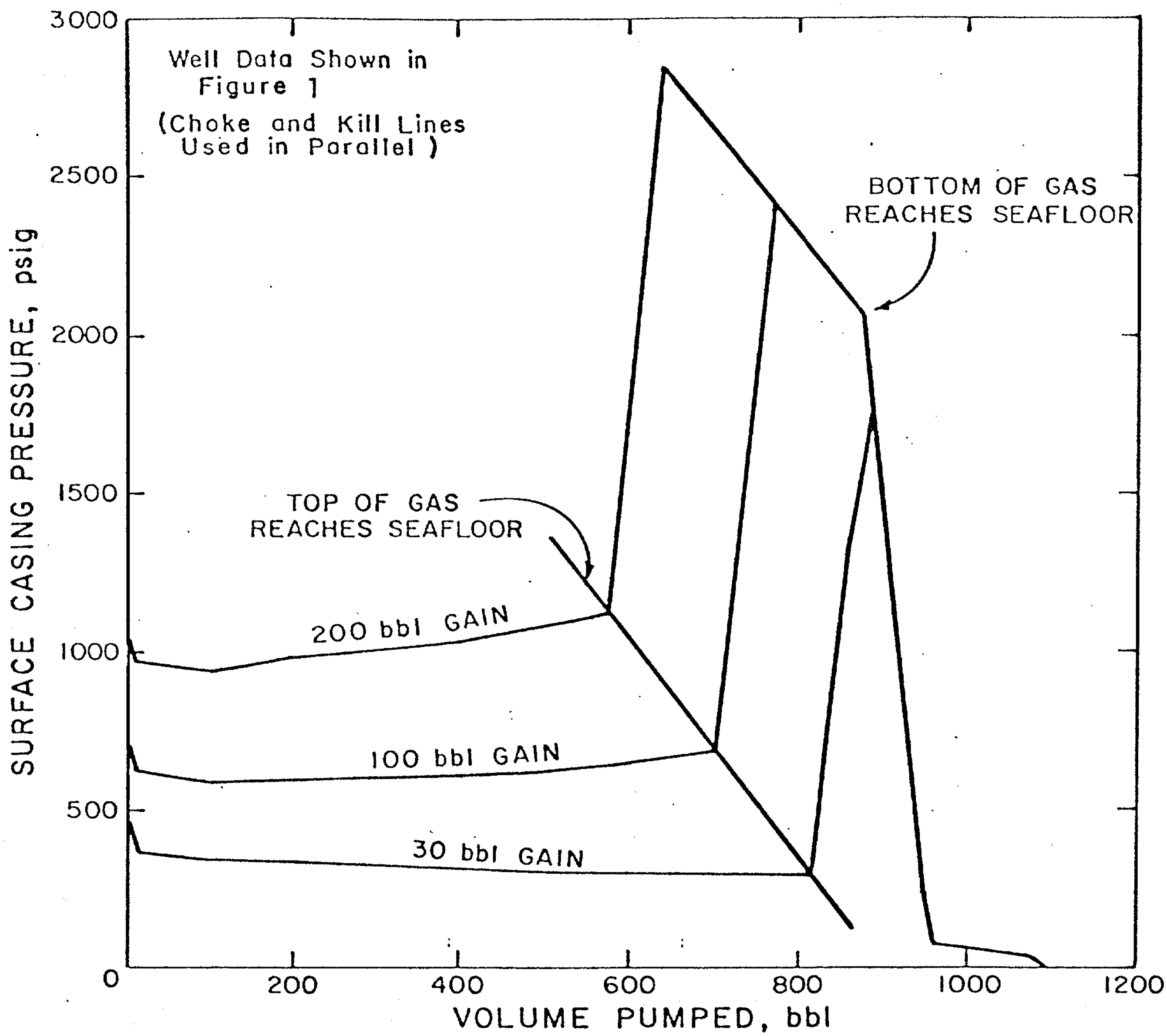


Figure 3: Example Illustrating Required Change in Choke Pressure When Gas Kick Reaches Sea Floor

transients to reach the surface can cause drill pipe pressure changes to lag significantly behind changes in bottom hole pressure.

In some cases, mechanical problems occur during well control operations which make it necessary to temporarily cease well circulation. Significant upward gas migration can occur due to gravity segregation during the shut-in period. Control problems can also occur in this situation when the top of the gas zone reaches the sea floor, especially if the mechanical problem causes a meaningful drill pipe pressure reading not to be available.

The current research program now underway at LSU involves the development of improved well control procedures for floating drilling operations. Under the sponsorship of the USGS, a well research facility has been designed physically modeling blowout control operations on a floating drilling vessel in deep water. Construction of the new facility is being accomplished under the dual support of industry and the USGS. A 9000 foot well with 7.625 in. casing and valued in excess of $400,000 has been acquired on the LSU campus which is suitable for use in the well facility needed to model the deep water well control process. The LSU Petroleum Engineering Department has been allocated a 1.4 acre tract of land containing the well by the University to support the development of the improved research facility. Shown in Figure 4, ia a flow schematic of the planned surface equipment installation.

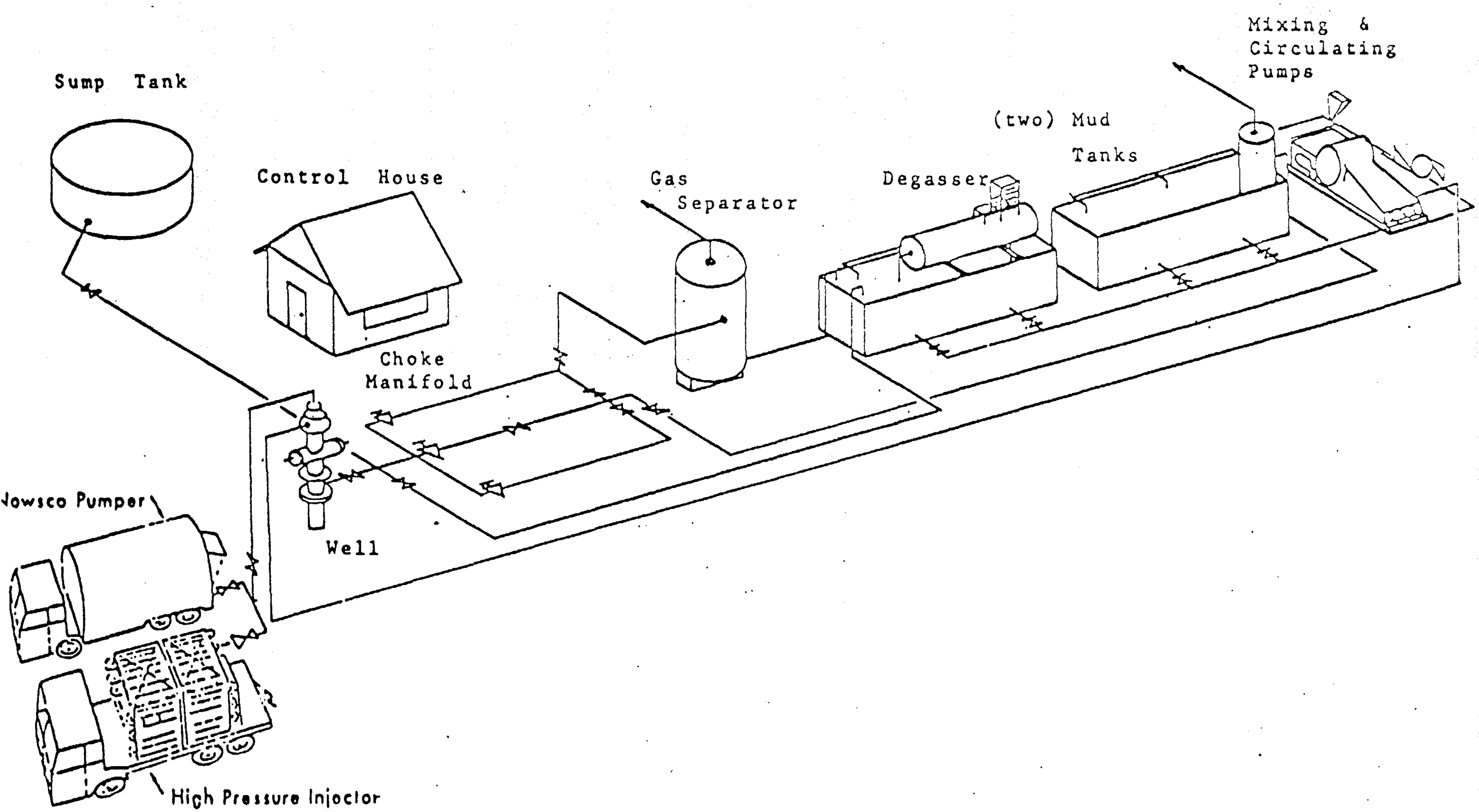
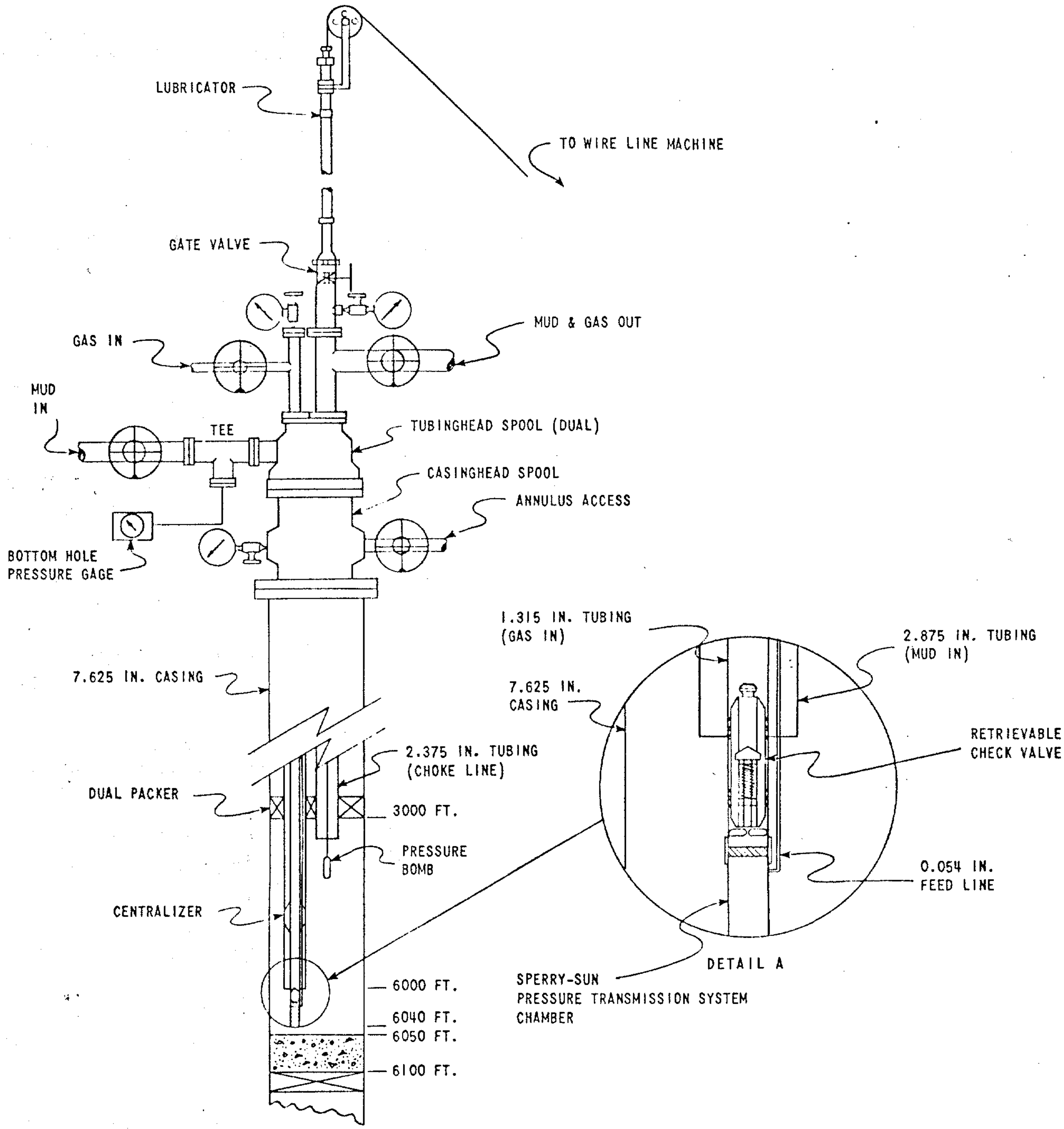


FIGURE 4 - SCHEMATIC OF PROPOSED
RESEARCH FACILITY

Figure 5 is a schematic of the proposed well completion. The effect of the blowout preventer being located at the sea floor would be modeled by the packer placed at a depth of 3000 feet in the well.

The design of the model well facility was aided by computer simulations of (1) a large number of well control operations for a large variety of deep water drilling operations and (2) a variety of model well geometrics. A current "state of the art" well control model was used in these simulations. This computer model assumes (1) that any formation gas which enters the well remains as a continuous slug which occupies the entire cross sectional area of the annulus during all of the well control operation, (2) that the gas does not slip with respect to the drilling fluid during the well control operations, and (3) the well control operator maintains the bottom hole pressure perfectly constant. While these assumptions are not entirely valid, the results obtained are felt to be sufficiently valid to allow a representative model well geometry to be selected. Figure 6 shows results of a computer simulation for the well geometry selected. A stated research objective of the model well is to allow an improved mathematical model of the well control process for floating drilling operations to be developed.

Experimental data on the flow characteristics of modern adjustable chokes and blowout preventers is being taken at an existing well site on the LSU campus. The existing well was constructed for blowout prevention training for land



SCHEMATIC OF PROPOSED RESEARCH WELL
FIGURE 5

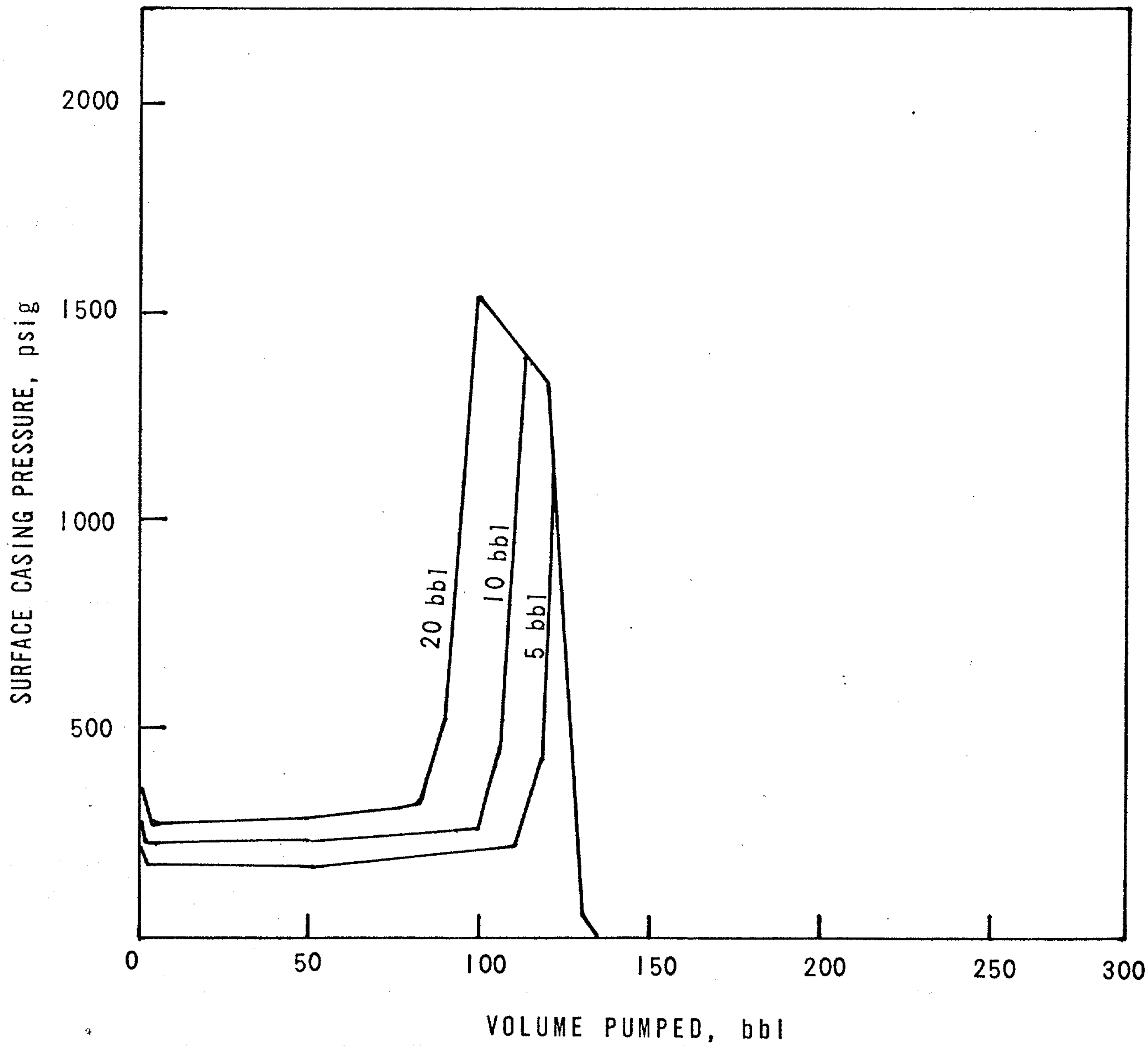


FIGURE 6: EXAMPLE CASING PRESSURE PROFILES COMPUTED FOR PROPOSED RESEARCH WELL FACILITY

based drilling operations. However, the equipment used on this phase of the research project would apply also to the surface equipment used in floating drilling operations. The data being collected should aid in the development of improved shut-in procedures as well as the development of an improved mathematical model of the well control process.